System Impact Study SPP-2004-009-1 For Network Service Requested By Southwestern Public Service Company

From SPS To SPS

For a Reserved Amount Of 9 MW From 7/1/2004 To 7/1/2019

SPP Engineering, Tariff Studies

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1. Executive Summary

Southwestern Public Service Company has requested a system impact study for Network Integration Transmission Service from SPS to SPS for 9 MW. The period of the service requested is from 7/1/2004 to 7/1/2019. The OASIS reservation number is 636893.

The principal objective of this study is to identify system constraints and potential system modifications necessary to grant the requested Network Service while maintaining system reliability. Due to higher priority requests, analysis was conducted to evaluate only the first year of service.

The requested service was studied using two System Scenarios with SPS exporting and importing, respectively. The service was modeled by transfers from SPS generation to the Network Load. Tables 1.1 and 1.2 list the SPS facility overloads caused or impacted by the transfers modeled using Scenario 1 and 2, respectively. Tables 2.1 and 2.2 list the SPS voltage violations caused or impacted by the transfers modeled using Scenario 1 and 2, respectively. No facilities outside of SPS were identified as being impacted with application of established transfer distribution factor cutoffs.

Due to the inability to upgrade limiting constraints identified for the first year of service, the ATC for the SPS to SPS 9 MW Network Service request is limited. SPS redispatch was evaluated as an option to obtain the first year of requested service. Generation shift factors and applicable redispatch relief pairs are documented in Tables 4 and 5, respectively. The curtailment or redispatch requirements would be called upon prior to implementing NERC TLR Level 5a.

If the customer agrees to redispatch the applicable SPS units to relieve the impacts on the limiting constraints identified during the first year of service, the request for Network Service will be accepted for the first year. The reservation queue priority of the remaining years of requested service will remain the same. SPP requests that a facility study agreement be executed. Upon execution of a facility study agreement, SPP will evaluate the remaining years of requested service and determine necessary transmission upgrades.

2. Introduction

Southwestern Public Service Company has requested a system impact study for Network Integration Transmission Service from SPS to SPS for 9 MW. The principal objective of this study is to identify the restraints on the SPP Regional Tariff System that may limit the requested service and determine the least cost solutions required to alleviate the limiting facilities. Due to higher priority requests, analysis was conducted to evaluate only the first year of service.

The study includes steady-state contingency analyses (PSS/E function ACCC) and Available Transfer Capability (ATC) analyses. The steady-state analyses consider the impact of the request on transmission line and transformer loadings, and bus voltages for outages of single transmission lines and transformers, and selected multiple transmission lines and transformers on the SPP system and first tier Non - SPP systems. Generation unit outages were performed for the SPS control area.

The requested service was studied using two System Scenarios with SPS exporting and importing, respectively. The two scenarios were studied to capture worst case system limitations dependent on the bias of the transmission system. The service was modeled by transfers from SPS generation to the Network Load.

3. Study Methodology

A. Description

The system impact analysis was conducted to determine the steady-state impact of the requested service on the SPP and first tier Non - SPP control area systems. The steady-state analysis was done to ensure current SPP Criteria and NERC Planning Standards requirements are fulfilled. The Southwest Power Pool conforms to the NERC Planning Standards, which provide the strictest requirements, related to voltage violations and thermal overloads during normal conditions and during a contingency. It requires that all facilities be within normal operating ratings for normal system conditions and within emergency ratings after a contingency. Normal operating ratings and emergency operating ratings monitored are Rate A and B in the SPP MDWG models, respectively. The lower bound of the normal voltage range monitored is 95%. The lower bound of the emergency voltage range monitored is 90%. The Tuco 230 kV bus voltage is monitored at 92.5% due to pre-determined system stability limitations.

The contingency set includes all SPP control area branches and ties 69kV and above, first tier Non - SPP control area branches and ties 115 kV and above, and any defined contingencies for these control areas. Generation unit outages for the SPS control area with SPP reserve share program redispatch were included in the contingency set. The monitor elements include all SPP control area branches, ties, and buses 69 kV and above, and all first tier Non – SPP control area branches and ties 69 kV and above. Voltage monitoring was performed for SPP control area buses 69 kV and above.

A 3 % transfer distribution factor (TDF) cutoff was applied to all SPP control area facilities. For first tier Non – SPP control area facilities, a 3 % TDF cutoff was applied to AECI, AMRN, and ENTR and a 2 % TDF cutoff was applied to MEC, NPPD, and OPPD. For voltage monitoring, a 0.02 per unit change in voltage must occur due to the transfer to be considered a valid limit to the transfer.

B. Model Updates

SPP used eight seasonal models to study the requested service for the first year of service. The SPP 2004 Series Cases Update 2 2004 Summer Peak (04SP), 2004 Summer Shoulder (04SH), 2004 Fall Peak (04FA), 2004/2005 Winter Peak (04WP), 2005 April Minimum (05AP), 2005 Spring Peak (05G), 2005 Summer Peak (05SP), and 2005 Summer Shoulder (05SH) were used to study the impact of the requested service on the transmission system during the first year of service from 7/1/2004 to 7/1/2005. The Spring Peak models apply to April and May, the Summer Peak models apply to June through September, the Fall Peak models apply to October and November, and the Winter Peak models apply to December through March.

The chosen base case models were modified to reflect the most current modeling information. From the eight seasonal models, two system scenarios were developed. Scenario 1 includes SWPP OASIS transmission requests not already included in the SPP 2004 Series Cases flowing in a West to East direction with ERCOT exporting and the SPS Control Area exporting to outside control areas and exporting to the planned Lamar HVDC Tie. Scenario 2 includes transmission requests not already included in the SPP 2004 Series Cases flowing in an East to West direction with ERCOT net importing and SPS importing from an outside control area and importing from the planned Lamar HVDC Tie. The system scenarios were developed to minimize counter flows to the transfers studied. The Lamar HVDC Tie is modeled starting in the 2004 Fall Peak.

The Network load for the 2004 Summer Peak was forecasted to be a maximum of 9 MW. Summer peaks were forecasted to increase 2.7% annually. The Network load amounts modeled for the spring peaks, fall peaks and winter peaks was 65% of the summer peaks. The Network load amount modeled in the summer shoulder is 85% of the summer peaks. The Network load amount for 2005 April minimum is 47% of the summer peaks. Future Summer Peak and Non-Summer Peak loads were determined by scaling the 2004 summer peak values while maintaining constant real power and reactive power ratios. Table 3 documents the total Network load modeled and the transfer amounts modeled in each seasonal case.

SPS currently has 3 MW of long-term firm point-to-point service to the Network Load. The existing reserved service was modeled in the cases before any transfer analysis was performed.

C. Transfer Analysis

The service was modeled by transfers from SPS generation to the Network Load. Using the selected cases both with and without the transfers modeled, the PSS/E Activity ACCC was run on the cases and compared to determine the facility thermal overloads and voltage violations caused or impacted by the transfer. The PSS/E options chosen to conduct the analysis can be found in Appendix A.

E. Upgrade Analysis

This system impact study does not include analysis of upgrades.

4. Study Results

A. Study Analysis Results

Tables 1.1, 2.1, 1.2, and 2.2 contain the steady-state analysis results of the System Impact Study. The Tables are in the attached workbook *SPP-2004-009-1 Tables*. The tables identify the seasonal case in which the event occurred, the transfer amount studied which does not include the existing 3 MW of firm service, the facility control area location, applicable ratings of the overloaded facility, the loading percentage or voltage with and without the studied transfer, the percent transfer distribution factor (TDF) if applicable, and the estimated ATC value using interpolation if calculated. Comments are provided in the tables to document any SPP or Non - SPP identification or assignment of the event, existing mitigations plans or criteria to disregard the event as a limiting constraint, upgrades and costs to mitigate a limiting constraint, or any specific study procedures associated with modeling an event.

Tables 1.1 and 1.2 list the SPP Facility Overloads caused or impacted by the transfers modeled from SPS generation to the Network Load using Scenario 1 and 2, respectively. Tables 2.1 and 2.2 list the SPP facility voltage violations caused or impacted by the transfers modeled from SPS generation to the Network Load using Scenario 1 and 2, respectively. No facilities outside of SPS were identified as being impacted with application of established transfer distribution factor cutoffs. Most SPS limitations identified were mitigated by implementing a modeling update and implementing and verifying SPS Operating Guides.

Table 4 lists SPS Generation Shift Factors for the PALODU - RANDALL COUNTY INTERCHANGE 115KV line, HAPPY INTERCHANGE - PALODU 115KV line, and HAPPY INTERCHANGE - TULIAT3 115KV line for the outage of AMARILLO S INTERCHANGE - SWISHER COUNTY INTERCHANGE 230KV line identified as limiting service in 2005 April Minimum using Scenario 2. These factors are provided for SPS redispatch to relieve the facility loading by 0.7 MW from 4/1/2005 to 5/1/2005.

Table 5 lists applicable relief pairs with redispatch amounts required to relieve the limiting facilities by 0.7 MW from 4/1/2005 to 5/1/2005.

Tables 1.1a and 1.2a documents the modeling representation of the events identified in Tables 1.1 and 1.2 to include bus numbers and bus names.

5. Conclusion

Due to the inability to upgrade limiting constraints identified for the first year of service, the ATC for the SPS to SPS 9 MW Network Service request is limited. SPS redispatch was evaluated as an option to obtain the first year of requested service. Generation shift factors and applicable redispatch relief pairs are documented in Tables 4 and 5, respectively. The curtailment or redispatch requirements would be called upon prior to implementing NERC TLR Level 5a.

If the customer agrees to redispatch the applicable SPS units to relieve the impacts on the limiting constraints identified during the first year of service, the request for Network Service will be accepted for the first year. The reservation queue priority of the remaining years of requested service will remain the same. SPP requests that a facility study agreement be executed. Upon execution of a facility study agreement, SPP will evaluate the remaining years of requested service and determine necessary transmission upgrades.

Appendix A

PSS/E CHOICES IN RUNNING LOAD FLOW PROGRAM AND ACCC

BASE CASES:
Solutions - Fixed slope decoupled Newton-Raphson solution (FDNS)
1. Tap adjustment – Stepping
2. Area interchange control – Tie lines only
3. Var limits – Apply immediately
4. Solution options - X Phase shift adjustment
   _ Flat start
   _ Lock DC taps
   _ Lock switched shunts

ACCC CASES:
Solutions – AC contingency checking (ACCC)
1. MW mismatch tolerance – 0.5
2. Contingency case rating – Rate B
3. Percent of rating – 100
4. Output code – Summary
5. Min flow change in overload report – 1mw
6. Excld cases w/ no overloads form report – YES
7. Exclude interfaces from report – NO
8. Perform voltage limit check – YES
9. Elements in available capacity table – 60000
10. Cutoff threshold for available capacity table – 99999.0
11. Min. contng. case Vltg chng for report – 0.02
12. Sorted output – None

Newton Solution:
1. Tap adjustment – Stepping
2. Area interchange control – Tie lines only
3. Var limits - Apply automatically
4. Solution options - X Phase shift adjustment
   _ Flat start
   _ Lock DC taps
   _ Lock switched shunts

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Table 1.1 - SPP Facility Overloads
Caused or Impacted by Transfer Using Scenario 1

Southwest Power Pool
System Impact Study

Study Case	Transfer Amount (MW)	From Area	To Area	Monitored Branch Overload	Rate <MVA>	BC % Loading	TC % Loading	%TDF	Outaged Branch Causing Overload	ATC (MW)	Solution
04SP	6			NONE IDENTIFIED						6	
04SH	4.7			NONE IDENTIFIED						4.7	
04FA	2.9			NONE IDENTIFIED						2.9	
04WP	2.9			NONE IDENTIFIED						2.9	
05AP	1.2			NONE IDENTIFIED						1.2	
05G	3			NONE IDENTIFIED						3	
05SP	6.2	SPS	SPS	LUBBOCK EAST INTERCHANGE 230/115KV TRANSFORMER	172.5	100.1	100.3	4.8	LUBBOCK SOUTH INTERCHANGE 230/115KV TRANSFORMER	6.2	Relieved by Updating Models with LH-AIKN2 (51367) to AIKENT2 (51365) Normally Closed and LH-AIKN2 (51367) to IRICK2 (51513) Normally Open
05SH	4.8			NONE IDENTIFIED						4.8	
											Total Estimated Cost

Estimated Cost
$0

Study Case	Transfer Amount (MW)	AREA	Monitored Bus with Violation	BC Voltage (PU)	TC Voltage (PU)	Outaged Branch Causing Voltage Violation	ATC (MW)	Solution	Estimated Cost
04SP	6		NONE IDENTIFIED				6		
04SH	4.7		NONE IDENTIFIED				4.7		
04FA	2.9		NONE IDENTIFIED				2.9		
04WP	2.9		NONE IDENTIFIED				2.9		
05AP	1.2		NONE IDENTIFIED				1.2		
05G	3		NONE IDENTIFIED				3		
05SP	6.2		NONE IDENTIFIED				6.2		
05SH	4.8		NONE IDENTIFIED				4.8		
								Total Estimated Cost	$0

Study Case	Transfer Amount (MW)	From Area	To Area	Monitored Branch Overload	Rate <MVA>	BC % Loading	TC % Loading	%TDF	Outaged Branch Causing Overload	ATC (MW)	Solution	Estimated Cost
04SP	6	SPS	SPS	NORTHWEST INTERCHANGE 115/69KV TRANSFORMER	46	114.0	114.7	5.3	HASTNGS2 - VAN BUREN 1 TAP 69KV	6	Relieved by SPS Operating Procedure to a. Close Normally Open Line Between 34THST2 (50991) & SOUTH GEORGIA INTERCHANGE (51007).	
04SH	4.7			NONE IDENTIFIED						4.7		
04FA	2.9			NONE IDENTIFIED						2.9		
04WP	2.9			NONE IDENTIFIED						2.9		
05AP	1.2	SPS	SPS	PALODU - RANDALL COUNTY INTERCHANGE 115KV	99	119.7	120.4	59.0	AMARILLO S INTERCHANGE - SWISHER COUNTY INTERCHANGE 230KV	1.2	Impact Relieved by SPS Redispatch See Table 5	
05AP	1.2	SPS	SPS	HAPPY INTERCHANGE - PALODU 115KV	99	118.8	119.5	59.2	AMARILLO S INTERCHANGE - SWISHER COUNTY INTERCHANGE 230KV	1.2	Impact Relieved by SPS Redispatch See Table 5	
05AP	1.2	SPS	SPS	HAPPY INTERCHANGE - TULIAT3 115KV	99	104.2	104.9	51.7	AMARILLO S INTERCHANGE - SWISHER COUNTY INTERCHANGE 230KV	1.2	Impact Relieved by SPS Redispatch See Table 5	
05G	3			NONE IDENTIFIED						3		
05SP	6.2			NONE IDENTIFIED						6.2		
05SH	4.8			NONE IDENTIFIED						4.8		
											Total Estimated Cost	$0

Study Case	Transfer Amount (MW)	AREA	Monitored Bus with Violation	BC Voltage (PU)	TC Voltage (PU)	Outaged Branch Causing Voltage Violation	ATC (MW)	Solution	Estimated Cost
04SP	6		NONE IDENTIFIED				6		
04SH	4.7		NONE IDENTIFIED				4.7		
04FA	2.9		NONE IDENTIFIED				2.9		
04WP	2.9		NONE IDENTIFIED				2.9		
05AP	1.2		NONE IDENTIFIED				1.2		
05G	3		NONE IDENTIFIED				3		
05SP	6.2		NONE IDENTIFIED				6.2		
05SH	4.8		NONE IDENTIFIED				4.8		
								Total Estimated Cost	$0

Study Case	Network Load (MW)	Network Load (MVAR)	Transfer Amount (MW)	Existing Service Modeled to Network Load (MW)
04SP	9	3.5	6	3
04SH	7.7	3	4.7	3
04FA	5.9	2.3	2.9	3
04WP	5.9	2.3	2.9	3
05AP	4.2	1.6	1.2	3
05G	6	2.3	3	3
05SP	9.2	3.5	6.2	3
05SH	7.8	3	4.8	3

Limiting Facility 1: PALODU - RANDALL COUNTY INTERCHANGE 115KV
Limiting Facility 2: HAPPY INTERCHANGE - PALODU 115KV
Limiting Facility 3: HAPPY INTERCHANGE - TULIAT3 115KV
Line Outage for Limiting Facilities: AMARILLO S INTERCHANGE - SWISHER COUNTY INTERCHANGE 230KV
Date Redispatch Needed: 4/1/05-5/1/05
Relief Amount: 0.7 MW

Source	Sink	GSF-1	GSF-2	GSF-3
SPS_LP-MACK269.0	System Swing	-0.06964	0.06964	-0.06964
SPS_LP-HOLL269.0	System Swing	-0.06944	0.06944	-0.06944
SPS_LP-BRND269.0	System Swing	-0.06978	0.06978	-0.06978
SPS_MRG3 112.5	System Swing	0.05927	-0.05927	0.05927
SPS_RVRV GT113.8	System Swing	0.06326	-0.06326	0.06326
SPS_HUBRCO 269.0	System Swing	0.06327	-0.06327	0.06327
SPS_SIDRCH 269.0	System Swing	0.06327	-0.06327	0.06327
SPS_SIDRCH 269.0	System Swing	0.06327	-0.06327	0.06327
SPS_BLKHK1 113.8	System Swing	0.06316	-0.06316	0.06316
SPS_BLKHK2 113.8	System Swing	0.06316	-0.06316	0.06316
SPS_CZ1 113.8	System Swing	0.06126	-0.06126	0.06126
SPS_CZ2 113.8	System Swing	0.06126	-0.06126	0.06126
SPS_HARRNG1124.0	System Swing	0.0617	-0.0617	0.0617
SPS_HARRNG2124.0	System Swing	0.0617	-0.0617	0.0617
SPS_HARRNG3124.0	System Swing	0.0617	-0.0617	0.0617
SPS_NICHOL1113.8	System Swing	0.06999	-0.06999	0.06999
SPS_NICHOL2113.8	System Swing	0.06999	-0.06999	0.06999
SPS_NICHOL3122.0	System Swing	0.06194	-0.06194	0.06194
SPS_TUCUM 113.2	System Swing	-0.03119	0.03119	-0.03119
SPS_PLNTX1 113.8	System Swing	-0.05274	0.05274	-0.05274
SPS_PLNTX2 113.8	System Swing	-0.05274	0.05274	-0.05274
SPS_PLNTX3 113.8	System Swing	-0.05274	0.05274	-0.05274
SPS_PLNTX4 120.0	System Swing	-0.03486	0.03486	-0.03486
SPS_TOLK1 124.0	System Swing	-0.03907	0.03907	-0.03907
SPS_TOLK2 124.0	System Swing	-0.03904	0.03904	-0.03904
SPS_JONES1 122.0	System Swing	-0.06888	0.06888	-0.06888
SPS_JONES2 121.0	System Swing	-0.06888	0.06888	-0.06888
SPS_MUSTG1 113.8	System Swing	-0.05072	0.05072	-0.05072
SPS_MUSTG2 113.8	System Swing	-0.05073	0.05073	-0.05073
SPS_MUSTG3 122.0	System Swing	-0.0496	0.0496	-0.0496
SPS_CUNN1 113.8	System Swing	-0.04836	0.04836	-0.04836
SPS_CUNN2 120.0	System Swing	-0.04719	0.04719	-0.04719
SPS_CUNN4 122.0	System Swing	-0.04719	0.04719	-0.04719
SPS_CUNN3 122.0	System Swing	-0.04836	0.04836	-0.04836
SPS_CARLSBD113.8	System Swing	-0.04517	0.04517	-0.04517
SPS_MADDX1 113.8	System Swing	-0.04859	0.04859	-0.04859
SPS_MADDX2 113.8	System Swing	-0.04859	0.04859	-0.04859
SPS_MADDX3 113.8	System Swing	-0.04859	0.04859	-0.04859

Relief Amount = ATC (MW) Needed * SPS to SPS %Response

Limiting Facility 1: PALODU - RANDALL COUNTY INTERCHANGE 115KV
Limiting Facility 2: HAPPY INTERCHANGE - PALODU 115KV
Limiting Facility 3: HAPPY INTERCHANGE - TULIAT3 115KV
Line Outage for Limiting Facilities: AMARILLO S INTERCHANGE - SWISHER COUNTY INTERCHANGE 230KV
Date Redispatch Needed: 4/1/05-5/1/05
Relief Amount: 0.7 MW

Source	Sink	Factor	Redispatch Amount (MW)
SPS_MUSTG1 113.8	SPS_HARRNG1124.0	-0.11242	6
SPS_MUSTG2 113.8	SPS_HARRNG1124.0	-0.11243	6
SPS_MUSTG3 122.0	SPS_HARRNG1124.0	-0.1113	6
SPS_LP-MACK269.0	SPS_HARRNG1124.0	-0.13134	5
SPS_CUNN4 122.0	SPS_HARRNG1124.0	-0.10889	6
SPS_JONES2 121.0	SPS_HARRNG1124.0	-0.13058	5

Factor = Source GSF Referenced to System Swing - Sink GSF Referenced to System Swing
Transaction = Relief Amount / Factor
Note: Redispatch Source, Sink, and Amount is the same for each limiting facility

Study Case	Transfer Amount (MW)	From Area	To Area	Monitored Branch Overload	Rate <MVA>	BC % Loading	TC % Loading	%TDF	Outaged Branch Causing Overload	ATC (MW)	Solution	Estimated Cost
04SP	6									6		
04SH	4.7									4.7		
04FA	2.9									2.9		
04WP	2.9									2.9		
05AP	1.2									1.2		
05G	3									3		
05SP	6.2	SPS	SPS	51688 LUBE3 115 to 51689 LUBE6 230 CKT 1	172.5	100.1	100.3	4.8	51680 LUBS3 115 to 51681 LUBS6 230 CKT 1	6.2	Relieved by Updating Models with LH-AIKN2 (51367) to AIKENT2 (51365) Normally Closed and LH-AIKN2 (51367) to IRICK2 (51513) Normally Open	
05SH	4.8									4.8		
											Total Estimated Cost	$0

Study Case	Transfer Amount (MW)	From Area	To Area	Monitored Branch Overload	Rate <MVA>	BC % Loading	TC % Loading	%TDF	Outaged Branch Causing Overload	ATC (MW)	Solution	Estimated Cost
04SP	6	SPS	SPS	50937 NORTHW2 69 to 50938 NORTHW3 115 CKT 1	46	114.0	114.7	5.3	50949 HASTNGS2 69 to 50961 VB1TAP2 69 CKT 1	6	Relieved by SPS Operating Procedure to a. Close Normally Open Line Between 34THST2 (50991) & SOUTH GEORGIA INTERCHANGE (51007).	
04SH	4.7									4.7		
04FA	2.9									2.9		
04WP	2.9									2.9		
05AP	1.2	SPS	SPS	51020 RANDALL3 115 to 51082 PALODU 3 115 CKT 1	99	119.7	120.4	59.0	51041 AMARLS6 230 to 51321 SWISHER6 230 CKT 1	1.2	Impact Relieved by SPS Redispatch See Table 5	
05AP	1.2	SPS	SPS	51082 PALODU 3 115 to 51302 HAPPY3 115 CKT 1	99	118.8	119.5	59.2	51041 AMARLS6 230 to 51321 SWISHER6 230 CKT 1	1.2	Impact Relieved by SPS Redispatch See Table 5	
05AP	1.2	SPS	SPS	51302 HAPPY3 115 to 51310 TULIAT3 115 CKT 1	99	104.2	104.9	51.7	51041 AMARLS6 230 to 51321 SWISHER6 230 CKT 1	1.2	Impact Relieved by SPS Redispatch See Table 5	
05G	3									3		
05SP	6.2									6.2		
05SH	4.8									4.8		
											Total Estimated Cost	$0